Energy Policy 116 (2018) 112–126

Contents lists available at ScienceDirect

Energy Policy

journal homepage: www.elsevier.com/locate/enpol

How can the renewables targets be reached cost-effectively? Policy options for the development of renewables and the transmission grid☆

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ARTICLE INFO

Keywords:
Renewables development
Support policies
Transmission grid development
Power system

ABSTRACT

Increasing the share of renewable energy sources in the electricity sector (RES-E) contributes to achieving the European energy and climate targets including a 27% share of renewables in final energy consumption by 2030. We assess the future costs of the power sector for different RES-target levels and support schemes including generation costs, system operation costs and transmission grid development costs based on three power sector models. The results show similar power system costs for different target levels. RES-E shares below 70% involve limited infrastructure costs that are below 2.6% of the overall system costs. The impacts of the modelled RES-E policies, an EU quota and national feed-in premiums on transmission costs are ambiguous: Contrary to expectations, the costs of transmission network development under quota obligations are lower than under technology-specific feed-in premiums for RES-E penetration levels up to 50%. The drivers of transmission costs include not only a concentration of renewable capacity, but also the exact location of RES-E capacity with respect to existing power plants and the strength of the existing infrastructure. Quota obligations lead to higher grid costs than feed-in premiums if the RES-E share amounts to 70% due to the stronger regional concentration of RES power plants.

1. Introduction

There are various pathways ensuring the transition to a low carbon economy that focus on different technology options. The increased use of renewable energy sources (RES) plays a major role in achieving low-carbon targets. When considering different technology pathways towards a future low-carbon energy system, the associated cost aspects play a crucial role and require a sound knowledge of the total energy system costs. Accordingly, the European Council has agreed to increase the share of RES in final energy consumption to 27% by 2030 as part of the 2030 framework for energy and climate policies (European Council, 2014). The question arises whether higher shares of RES than the envisaged 27% would make sense from an economic viewpoint given the fact that the European Commission's impact assessment already estimates the RES-share at 26.4%, triggered only by the 40% greenhouse gas emission reduction target and without a dedicated RES-target (European Commission, 2014b). Both this impact assessment as well as a further in-depth analysis (Duscha et al., 2016, 2014) have shown that a higher RES share, such as 30%, can lead to higher macro-economic benefits compared to a RES-share of 27%. In these studies, the positive macro-economic effects result mainly from higher investments and lower use of fossil (imported) fuels, whereas potential negative impulses come from higher consumer bills driven by the additional costs of renewable energy. To date, the power sector accounts for the highest RES-investments as well as the highest additional costs of these technologies. Due to the rapid learning taking place in key RES-E technologies, their cost disadvantage diminishes quickly and allows higher capacity additions without compromising the macro-economic benefits. Therefore, our analysis concentrates on the impact of different RES-E pathways on the system costs of the electricity sector considering generation and transmission. Due to the prominent role of the power sector in decarbonising the economy, the issue of estimating the future costs of the power sector by 2030 for different RES-target levels has risen up the agenda. Relevant cost components include the conversion costs of the technologies used as well as the costs occurring due to the integration of variable renewable electricity (RES-E) into the power

☆ Topic: Energy Conversion, Transportation/Transmission, and Storage.

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https://doi.org/10.1016/j.enpol.2018.01.025
Received 12 June 2017; Received in revised form 4 December 2017; Accepted 11 January 2018

system, including the need for the grid infrastructure and storage options. Accordingly, energy system models face new challenges due to the increasing share of variable RES-E and flexible demand profiles and require a higher spatial and temporal resolution (see e.g. Pfenninger et al., 2014). However, as pointed out by (Després et al., 2015), there is a lack of models combining long-term investment decisions in the power sector with system operation and the development and the use of the grid infrastructure. Existing long-term energy models are often characterised by a coarse spatial and temporal resolution and a systemic view (Després et al., 2015). The reasons for this are limited data availability – representing the grid is only useful if regionally disaggregated supply and demand data are available (Després et al., 2015) – and the computational tractability of optimisation models (Pfenninger et al., 2014). One model used by (Haller et al., 2012), the LIMES-EU$^+$ model, has been applied to develop long-term decarbonisation scenarios for the EU and MENA-region, taking into account short-term dynamics and spatial aspects including the development of grid infrastructure. However, its temporal resolution based on characteristic time slices of 6 h remains too coarse to represent very short time scales. Although the authors do not specify how grid infrastructure is represented in terms of geographical resolution, it seems that grid extension options follow a simplified approach reflecting the transmission of electricity between but not within countries based on net transfer capacities. This simplification and the low geographical resolution involve considerable uncertainties assuming standard distances between regions or countries. In reality, interconnections between regions tend to cover much smaller distances, in particular for early reinforcements and national reinforcements.

Taking a closer look at existing studies on the development of the European transmission grid, it becomes clear that few have analysed the impact on network costs of the location and type of RES generation considered in the system development. Much of the work on transmission network development in Europe concludes that the CO_2 emission reduction achieved (Egerer et al., 2015; Holz and Hirschhausen, 2013), and the degree of RES penetration (Couckuyt et al., 2015; European Commission, 2011; Fürsch et al., 2013; Gaxiola, 2012; Holz and Hirschhausen, 2013) are major drivers of transmission development costs, and contribute to increasing them. Some of them even conclude that the type of clean technologies deployed (RES generation, energy efficiency) and their geographical location, or distribution in the system, barely affect transmission costs (Egerer et al., 2015; Holz and Hirschhausen, 2013). However, some other studies recognise the clear impact of the geographical distribution of RES generation on network (transmission and/or distribution) costs. Thus, according to (Couckuyt et al., 2015) and (Greenpeace, 2011), network development costs are significantly larger when RES generation is deployed following a centralized approach than when it is widely spread.

Concerning the formulation of the transmission network development problem, some of the previous studies represent the network in Europe in detail, but only a reduced set of operating situations, see (ECF, 2010; Egerer et al., 2015; Frías et al., 2013; Holz and Hirschhausen, 2013). In other studies, a wide range of operating situations is taken into account, but the network representation is coarse, since only one node is used to represent each country, see (ECF, 2010; European Commission, 2011; Holz and Hirschhausen, 2013). Similarly, (Pleßmann and Blechinger, 2017) realise a joint optimisation of generation, storage and transmission to analyse European power supply in the context of reaching the EU greenhouse gas emissions reduction target by 2050, but their representation of the grid infrastructure with only 18 regions remains sketchy.

Some studies feature a detailed network model and a wide range of system operating conditions. However, in most of them, the computed network reinforcements are not optimal, because the benefits produced by potential reinforcements are assessed by including them only sequentially in the network and not by jointly optimising generation and transmission over the entire time horizon. This leads to the computation of reasonable, though largely suboptimal, reinforcements, as in (Couckuyt et al., 2015; ENTSO-e, 2014; Greenpeace, 2011). The reason for suboptimal results is the use of heuristic algorithms in large problems if not all the possible solutions to the problem have been explored. This is typically the case if the development of the network is determined by sequentially considering potential reinforcements (Banez Chicharro et al., 2017). An exception to this may be the work in (Hagspiel et al., 2014), where the development of generation and transmission in Europe is jointly and centrally optimised. However, this optimisation over all EU Member States does not respect existing political constraints and regulations such as the national RES-targets required by Directive 2009/28/EC (The European Parliament and the Council of the European Union, 2009). The approach followed in the analysis described here achieves an appropriate balance between the level of detail considered in the representation of both the grid and the variability in system operating conditions. At the same time, the transmission expansion planning problem is solved through the application of classical optimisation techniques. This should lead to the computation of the optimal development of the grid, provided a valid solution is found by the algorithm.

Our analysis uses two scenarios to compare the overall costs of RES development including generation costs, system integration costs and infrastructure-related costs. One scenario applies a technology-neutral quota obligation to achieve low-cost RES development. The other scenario applies technology-specific feed-in premiums for a more balanced RES development. In this context, we expect the costs related to the required grid infrastructure to be higher for RES-scenarios with stronger regional concentration. A Europe-wide quota system should lead to higher regional concentration because of the technology and EU-wide optimisation and therefore to higher infrastructure costs than a technology-specific feed-in premium. The technology-specific feed-in premium incentivises a portfolio of RES technologies with a more even distribution of RES capacity across all EU MS. We explore whether technology-specific feed-in premiums imply lower grid costs compared to a European-wide technology-neutral quota system, as is often supposed, and apply a modelling approach with a high temporal and geographical resolution to reflect the impact of renewables support policies on system and grid costs.

2. Methodology

For the model-based approach, we combine three different energy sector models. RES-deployment pathways are modelled using the simulation model Green-X in order to reflect the impact of energy policy instruments on RES-deployment and the related costs and benefits for EU-countries. These RES-deployment pathways are then fed into the power sector model Enertile in order to analyse the development of the power sector as a whole. A comprehensive optimisation of the European power sector until 2050 is carried out including the detailed modelling of renewable generation data with high spatial and temporal resolution. Capacity planning for conventional power plants, the operation of the power system and grid extension, reinforcement and management are taken into account. Results of Enertile are then included in a second modelling iteration of renewables development in Green-X so that both models produce consistent output. In the final stage, the grid model TEPES uses the power generation results in order to assess transmission grid-related issues of RES-E integration in more detail. The system network development and operating costs produced by TEPES are considered together with the data for cost components related to electricity generation from Enertile to produce an estimate of the total RES-integration costs associated with the different RES generation strategies and RES targets analysed. The results produced by TEPES were not iterated with Enertile due to the extensive effort this would involve and the low additional benefit expected. Since generation/storage costs are normally much higher than network costs, it is unlikely that considering the network development costs associated with the installation of generation from TEPES would lead to a development and operation of generation that is significantly different from the one originally computed by Enertile.

2.1. Modelling RES-deployment with Green-X

Green-X is a specialized energy system model that has been used in several impact assessments and research studies related to RES. The core strengths of this tool are its detailed representation of renewable energy resources and technologies, and its comprehensive incorporation of energy policy instruments. This makes it possible to assess different policy design options with respect to the resulting costs, expenditures and benefits, as well as environmental impacts.

Geographically, Green-X covers the EU28, the Contracting Parties of the Energy Community (West Balkans, Ukraine, and Moldova) and other selected EU neighbours (Turkey, North African countries). It allows detailed assessments of RES demand and supply as well as of the related costs (including capital expenditures, additional generation cost of RES compared to conventional options, consumer expenditures due to applied support policies) and benefits (for instance, avoidance of fossil fuels and corresponding carbon emission savings). The Green-X model develops country-specific dynamic cost-resource curves for all key RES technologies in the electricity, heat and transport sectors. Besides the formal description of RES potentials and costs, Green-X includes a detailed representation of dynamic aspects such as technology learning and technology diffusion.

Through its in-depth representation of energy policy, the Green-X model can assess the impact of applying (combinations of) different energy policy instruments at both country or European level in a dynamic framework.[1] Further details on the Green-X model and its use are provided on the model's web page (www.green-x.at), while the approach used is described in detail in (Resch, 2005).

2.2. Modelling the power sector with Enertile

Enertile is an optimisation model used to analyse long-term developments in the power sector based on linear optimisation.[2] It is based on the integrated optimisation of investments in main assets in the power sector (power plants, cross-border transmission grids, flexibility options such as demand-side-management or power-to-heat storage technologies) and the dispatch of the respective technologies (see Fig. 1). As the model features high technology, spatial and temporal resolution, it is well suited to analysing the impacts of integrating RES-E into the electricity system. The modelling takes into account the most recent assessments of the dynamic development of technology costs. It considers location-specific characteristics of RES including the available resource potential (e.g. available amount of biomass) and detailed generation profiles depending on weather conditions (e.g. wind speed, solar irradiation). In addition, technology specifics that affect the electricity generation costs are taken into account. For example, with regard to onshore wind, the model chooses the optimal configuration of wind turbines depending on the wind regime, hub height and the relation between rated power and rotor area. The model distinguishes two exemplary turbine types, one designed for weaker wind speeds and the other for stronger wind speeds (Pfluger et al., 2017). Among other options, such as extending the electricity grid in a simplified way or using storage options, Enertile also considers the curtailment of electricity as one option to deal with excess generation. Typically, the model only selects this option if the alternatives such as building new transmission lines (implemented following a simplified approach) or the use of storage are more costly.

[1] Examples for policy instruments include quota obligations based on tradable green certificates / guarantees of origin, (premium) feed-in tariffs, tax incentives, investment incentives or the impact of emission trading on reference energy prices.

[2] For a more detailed description see: http://www.enertile.eu/enertile-en/methodology/.

2.3. Modelling transmission grid development with TEPES

The Enertile model provides a first estimate of the transmission network development needs associated with the evolution of the European system in each of the policy scenarios considered. This estimate is further refined with the help of TEPES. TEPES jointly optimises the expansion of the European transmission system and the system operation in the years 2030 and 2050. Considering additional points in time would provide more information about the future evolution of the system. However, these two dates were deemed sufficiently representative of the system evolution in the medium term, which is already conditioned by existing expansion plans, and the long term, normally represented in most studies by the year 2050. TEPES is a decision support model aimed at defining the transmission expansion plan for a large-scale electricity grid system in the long term. Candidate transmission lines (i.e. candidates to become network reinforcements) considered by TEPES may be pre-defined by the user or identified automatically by the model. In the analysis presented here, expert knowledge was applied to identify these candidate lines. TEPES produces a set of main and side results related to system operation and network development. A list of the main results follows:

- Size and technology of the reinforcements to the main transmission corridors in the European system in the considered time horizon (2030 and 2050) for each of the RES deployment scenarios considered, as well as their route. Based on these, the network development costs associated with each scenario are computed.
- Main operating variables for each scenario including the level of transmission losses, fuel costs, CO_2 emissions and electricity production by generation technology. The variables directly related to the existence of the transmission grid, namely the transmission losses, are taken as the final (most accurate possible) results of the analyses, while the final values for the other operating variables are drawn from results computed with Enertile.

When regarding the results produced by the model, one must be aware that RES energy curtailments are not included in the grid losses reported. This is because the RES generation (its output) reported is not gross, but net and is the result of deducting RES energy curtailments from the gross RES energy production available.

TEPES defines 118 regions to represent the European transmission network and allocates RES-E capacity to these regions according to the potential generation capacity in each, which has, in turn, been estimated based on the primary energy resource available. Further information on the modelling methodology is provided by (Lumbreras and Ramos, 2013).[3]

3. Scenario assumptions

3.1. General assumptions

Scenario storylines for this analysis are based on the PRIMES modelling realised for the Impact Assessment (European Commission, 2014b) and on previous scenario work on the Energy Roadmap 2050 (European Commission, 2011). Data include the development of future CO_2 and fuel prices as well as the future development of electricity demand. We include demand data, because we focus on modelling the supply side of the energy system. All the scenarios respect the current ILUC proposal for biofuels and the sustainability criteria for biomass heat/electricity beyond 2020. The first scenario "ETS-Only EE" assumes the ETS to be the main driver to achieve emission reductions of 40% by 2030 with additional energy efficiency measures to reduce final energy demand. No dedicated support is given to renewables after 2020; this

[3] See also https://www.iit.comillas.edu/aramos/TEPES.htm.

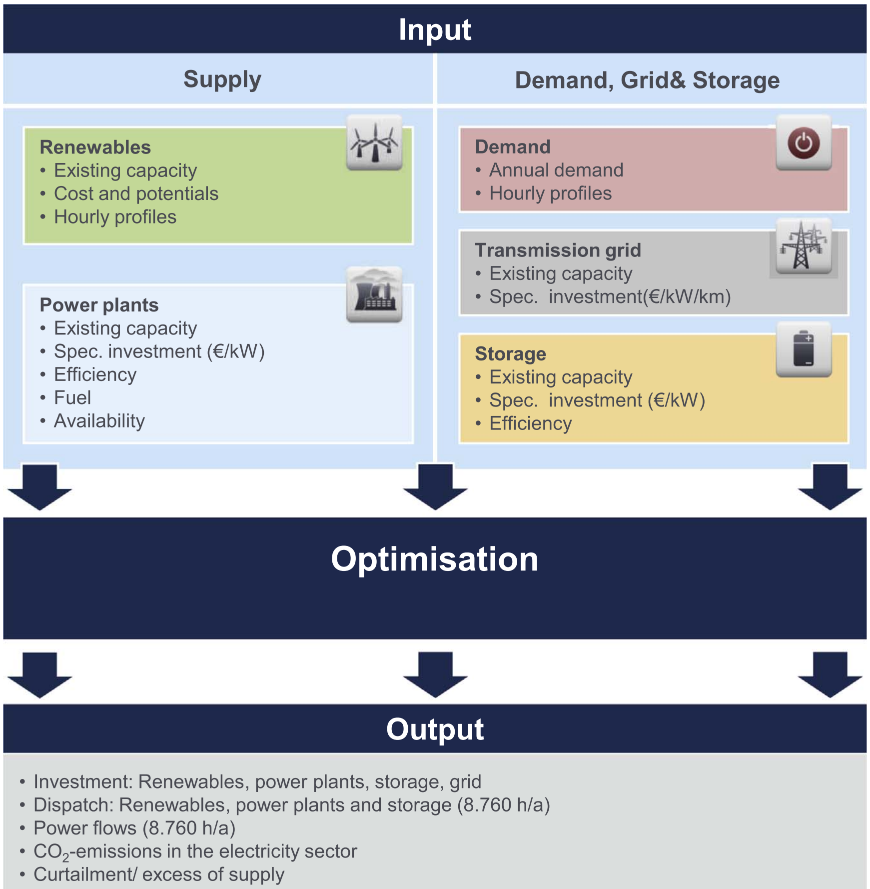

Fig. 1. Structure of the energy system optimisation model Enertile.

Table 1
Scenario overview.

Scenario Name	Description
ETS and energy efficiency "ETS-Only EE EE"	● 40% GHG emission reductions by 2030 ● ETS main driver for low-carbon technology support ● Energy efficiency measures in place ● Achievement of 2020 RES targets ● No dedicated support for RES beyond 2020 ● 26.4% RES share by 2030
Cost-optimised RES development "QUO – 30"	● 40% GHG emission reductions by 2030 ● ETS one driver for low-carbon technology support ● Energy efficiency measures in place ● Achievement of 2020 RES targets ● After 2020 continuation of RES support by means of an EU green certificate scheme. ● 30% RES-Share by 2030
Strengthened National Policies "SNP – 30"	● 40% GHG emission reductions by 2030 ● ETS one driver for low-carbon technology support ● Energy efficiency measures in place ● Achievement of 2020 RES targets ● Continuation of RES support with balanced RES support across countries in terms of a feed-in premium. ● 30% RES-Share by 2030

results in a RES share of 27% by 2030. In the scenario "QUO-30", policy settings regarding emission reductions and energy efficiency do not change, and we analyse the impact of a RES-target of 30%. This target is achieved by a technology-uniform quota obligation across all EU MS, incentivising a least-cost development of RES in terms of generation costs. The scenario "SNP-30" is similar to the "QUO-30" scenario with the difference that the renewables support provided via a technology-specific feed-in premium incentivises a portfolio of RES-E technologies. Table 1 provides a summary of the scenario storylines.

3.2. Discount rates

The economic decision-making leading to investment in energy technologies and the impact of overall investments on the total system costs depend strongly on the assumed discount rate. In our modelling, we assumed the discount rate to correspond to the minimum return an investor expects from an investment. This can be expressed by the weighted average cost of capital (WACC) that describes the equity and debt shares and costs. The minimum return expected by investors typically depends on the risk associated with an investment opportunity as well as on the risk of alternative private investments based on the concept of social opportunity costs.[4] Thus, we incorporate existing risk expectations to determine the WACC used in the modelling. In our default settings, we assume the WACC to amount to 6.5% for 2015, and to increase gradually to 7.5% by 2020. Multipliers modifying the default interest rate are introduced for additional policy-induced, technology-induced and country-specific risks. We use the following multipliers to depict the different risk premiums for RES market integration: 1.3 for ETS-based investments; 1.2 for the quota system; and 1.1 for feed-in premiums.

[4] Boardman et al. (2011) calculated a social opportunity cost rate of 7.3% when applying this approach to the United States based on the annual yields of long-term corporate bonds with AAA rating in the period from 1947 until 2005.

Table 2
CO_2 and fuel prices assumed for the scenarios based on (European Commission, 2014a).

	2010	2020	2030	2050
Oil [$€_{2010}$/boe]	60	89	93	110
Gas [$€_{2010}$/boe]	38	62	65	63
Coal [$€_{2010}$/boe]	16	23	24	31
CO2 [$€_{2010}$/t CO_2]				
ETS-Only EE	11	10	50	130
Quo – 30	11	10	11	152
SNP – 30	11	10	11	152

3.3. CO_2 and fuel prices

CO_2 prices and fuel prices (see Table 2) are based on the Impact Assessment by the (European Commission, 2014b). For the ETS-Only EE scenario, the CO_2 price was modified to align the RES-share by 2030 with the results from the Impact Assessment.

3.4. Electricity generation technologies

The modelling of future investment needs is based on the 2010 power plant portfolio featured in the World Electric Power Plants (WEPP) database.[5] Due to the high level of detail in this database and its influence on the calculation time of the model, individual power plants have been aggregated to some extent. Regarding future investment options, nuclear power plants are exogenous, provided their use is based on political strategies rather than commercial investment decisions. Thus, the future development of nuclear power plants in the EU in these scenarios is based on the current political plans of the Member States concerning the future use of nuclear power. We assume that countries supporting nuclear power will keep or renew their nuclear power plants, but still decrease their overall use in the longer term. Therefore, the installed nuclear capacity nearly halves from 117 GW in 2020–55 GW in 2050.

The use of lignite power plants is limited to Member States with their own lignite resources, given that transporting lignite is not cost-efficient due to its low energy density. The technology cost assumptions for future investments in electricity generation technologies are shown in Fig. 2.

3.5. Storage technologies

Enertile takes into account storage technologies to facilitate the integration of variable RES-E into the electricity system. Whilst the installed capacity and annual electricity generation of hydro reservoir plants is exogenous in Enertile, their use and dispatch is optimised endogenously. A simplified storage technology with characteristics similar to that of a pump storage plant is considered in Enertile as a representative storage option in order to keep computation time to an acceptable level. Other storage options such as adiabatic compressed air energy storage (CAES), hydrogen storage or batteries still involve substantially higher costs. However, the model does not choose to make significant use of the "cost-efficient" pump storage option, which justifies our simplification. The representative pump storage technology was assumed to have an efficiency of 80%, a specific investment of 1100 €/kW, fixed operation and maintenance costs of 10 €/(kW*a) and a lifetime of 40 years.

3.6. Electricity transmission grid

The transmission grid represented in the model comprises 118

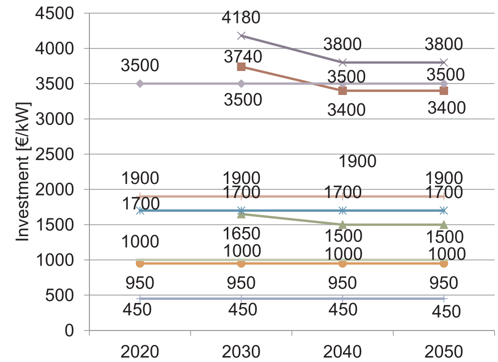

Fig. 2. Investment assumptions for the modelling in Enertile.

nodes, representing 118 areas within Europe. Elementary political-administrative regions within Europe have been clustered into these 118 areas according to the following variables: geographical location, electricity demand (which is assumed to be proportional to the population), area of land suitable for renewable power deployment, total installed conventional generation capacity, total installed renewable generation capacity, average wind speed and average irradiation level (representing their RES deployment potential).

The demand and generation in each country were allocated to these 118 areas according to the data available from the sources consulted, including the RES potential in each area, the population density in this area, and information available in Enipedia (TUDelft, 2016) about the location and features of already existing power plants.

Either AC or HVDC interconnections among areas in the network model were assumed. For already existing corridors, the respective technology is considered. Based on this, a simplified model has been computed of the European network for the year 2013 (see Fig. 3).

For candidate reinforcements to corridors, the choice of technology and the corresponding investment is made according to the length of each interconnection and the type of terrain to be crossed (submarine interconnectors should normally be HVDC). Both transmission lines and cables, and AC/DC converters are modelled.

A transmission model was used to represent the flow of power in the grid. This implements the first Kirchhoff law, referring to the balance of power at each node for both AC and HVDC lines. Losses are treated as proportional to the flow.

The optimal expansion of the European transmission grid was computed considering a reduced, but representative set of operating situations, or snapshots assumed to occur in the target year. This was done by carrying out an operation snapshot clustering analysis. Operating hours were grouped into clusters according to the distribution of the residual load (electricity demand minus gross renewable power output) across network areas. Based on this, a reduced number of snapshots (about 80 in the target year) were identified as the most representative. These were used to compute changes in the operation of the system resulting from the deployment of reinforcements to the network.

The 2020 grid formed the starting point for computing the required development of the transmission grid in each scenario and timeframe. This is due to the fact that the development of the regional transmission grid in Europe up to the year 2020 (meaning the grid of regional, or cross-border, significance) was already largely defined at the time this analysis was conducted. The European power system is expected to evolve in the same way in all scenarios up to the year 2020. After 2020, generation and network developments, and system conditions are expected to diverge in the different scenarios.

The 2020 network is constructed from the 2013 one to ensure its consistency with the 2022 NTC values as published by ENTSO-e in its 2012 Ten Year Network Development plan (TYNDP) (ENTSO-e, 2012). Table 3 shows the unit investment costs considered for the transmission

[5] For details on the database, please refer to: http://www.platts.com/Products/worldelectricpowerplantsdatabase.

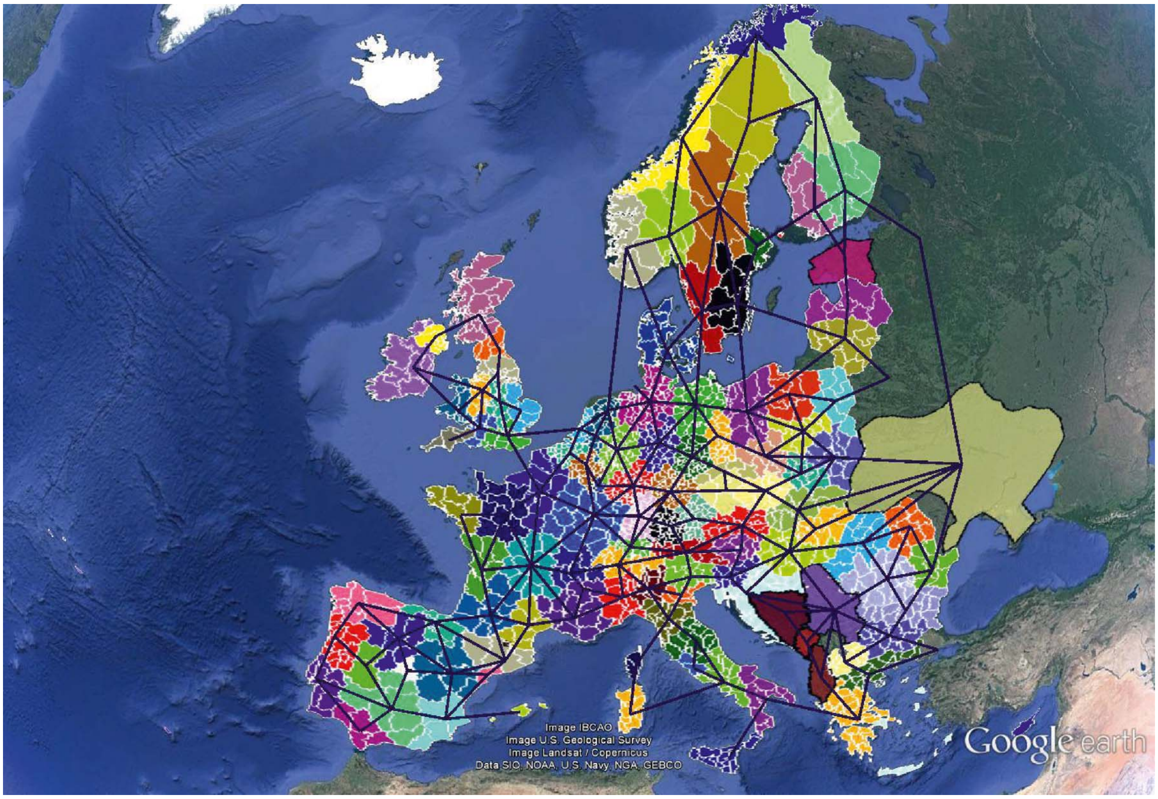

Fig. 3. Representation of the 2013 network model considered in the grid analyses.

Table 3
Unit investment for the transmission technologies considered in the analysis.

	Total Equivalent Fix Cost [€ / MW [km]]*		
	2020	2030	2050
DC line ground	440	469	830
AC line ground	1214	1307	2760
DC line submarine	1361	1361	993
AC/DC Converter	75,750	75,750	90,900

technologies and assets deemed to be suitable alternatives in the analysis.

4. Results and discussion

4.1. Technology mix

The development of the different technologies is partly exogenous, whilst other technologies evolve endogenously in Enertile and are therefore modelling results. Whilst the decline in nuclear generation capacity is driven exogenously, the future development of renewable energy technologies is an output of the Green-X model. All other technology options including thermal power plants compete with each other in Enertile and are deployed following a least-cost approach. The fact that nuclear generation capacity and RES-E development are driven exogenously in Enertile means that the model can only choose CCS-equipped fossil-fuel power plants as a low-carbon technology option. Due to the current problems with the commercialisation of CCS projects, we assume that CCS is not available by 2020 and only allow CCS development from 2020 onwards.

The results show an increased use of CCS in the ETS-Only EE Scenario, in particular, whilst an increasing use of RES is the main decarbonisation option in the two scenarios with a RES-target of 30% (see Fig. 4). With respect to CCS development, lignite CCS develops in a first step until 2030 in the ETS-Only EE scenario, reaching an installed capacity of 23 GW by 2030. In contrast, lignite CCS in the RES-target scenarios remains at a lower level of between 4 and 5 GW by 2030 due to the lower CO_2 price in 2030. Hard coal CCS does not develop at all in QUO-30 or in SNP-30 by 2030, but increases to 10 GW in both QUO-30 and SNP-30 by 2050. Looking at the CCS capacity in 2050, ETS-Only EE is clearly dominated by hard coal with roughly 80 GW of installed capacity, while lignite CCS capacities range from 36 GW in SNP-30 to 43 GW in ETS-Only EE.

The main driver of CCS development is the CO_2 price, which increases only slightly up to 2030, but experiences strong growth between 2030 and 2050. Thus, the use of lignite CCS starts to become competitive once the CO_2 price is roughly 50 € per ton of CO_2. Lignite CCS develops earlier due to the lower costs of lignite CCS compared to hard coal CCS. However, the use of CCS lignite equipment is limited to existing lignite power plants. As shown in Fig. 5, the overall lignite capacity increases only slightly between 2020 and 2050 in the ETS-Only EE scenario. By 2050, nearly all lignite power plants are equipped with CCS. Fig. 5 shows that the more expensive hard coal CCS option begins to develop strongly only after 2030.

With respect to the development of gas, the modelling results show a decrease of gas-based electricity generation capacity in all scenarios from 165 to 175 GW to 100–119 GW by 2050. It is notable that the additional gas power plants until 2030 are predominantly gas turbines, whilst the share of combined cycle gas turbines (CCGT) with CCS increases towards 2050. In combination with low electricity output, gas

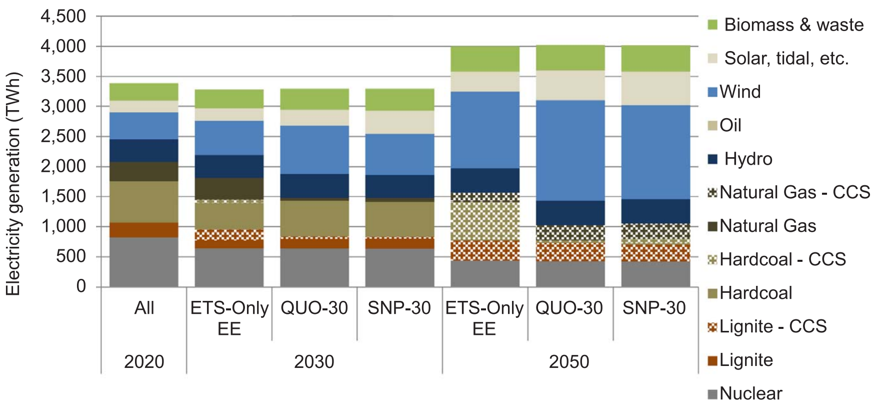

Fig. 4. Electricity generation in the EU in all considered scenarios.

turbines serve as peak load power plants in order to cover situations with low electricity generation availability and high loads. An additional 9 GW capacity of CCGT without CCS are built up to 2030 in the ETS-Only EE scenario, but this only occurs to a very limited extent in the RES target scenarios. The reason is the competitiveness of CCGT compared to other power plants in particular in the peak to medium load segment (covering annual full-load hours from 1000 h/a to 3000 h/a) in the ETS-Only EE scenario. This is due to the CO_2 price reaching 50 €/t of CO_2 by 2030. In contrast, the lower CO_2 price in the RES-target scenarios makes CCGT the most cost-efficient technology only for a very restricted range of utilisation between 1200 h/a and 1800 h/a. For higher utilisation rates, conventional lignite power plants are more competitive and lead to a lower share of CCGT and a higher share of lignite power plants (without CCS) in the RES-target scenarios. Further increases in the CO_2 price after 2050 make lignite power plants equipped with CCS the most competitive technology in the base load segment, whilst CCGT with CCS are more competitive in the medium load segment. Due to the lower CO_2 prices in the RES-target scenarios (QUO-30, SNP-30), there is more CCGT-CCS capacity by 2050 in the RES-target scenarios than in the ETS-Only EE scenario.

With regard to the share of RES in gross electricity demand, Table 4 shows that the 2020 target of a 20% RES-share translates into a slightly higher share of RES-E amounting to 35.3% in the ETS-Only EE scenario than in the RES target scenarios (RES-E share of 34.9%). This picture changes by 2030, when the RES-share of (nearly) 27% in the ETS-Only EE scenario translates into a RES-E share of 42.4%, whilst the 30% RES target requires higher RES-E shares of 52.5%. Finally, the lower CO_2 price by 2050 in combination with no dedicated RES-support leads to an overall RES-share of 52.8% in the ETS-Only EE scenario and to 57.1% in electricity (see Table 4). The share of RES in final energy consumption by 2050 is clearly higher in both RES-target scenarios, increasing to about 60% in both cases. Accordingly, the RES-E share amounts to about 70% in both RES-target scenarios.

Table 4
Development of the RES-E share in gross electricity demand in the EU28.

Scenario	2020	2030	2050
ETS-Only EE	35.3%	42.4%	57.1%
QUO – 30	34.9%	52.5%	70.3%
SNP – 30	34.9%	52.5%	69.7%

The modelling results show that curtailment in all the scenarios analysed remains negligible, even in the SNP-30 and QUO-30 scenarios with a RES-E share of about 70% by 2050. The highest curtailment is observed in the QUO-30 scenario, but even here, only 0.12% of gross electricity generation is curtailed. Experiences with previous modelling analyses have shown that curtailment only starts to become relevant at a RES-E share exceeding 80%. The fact that RES-E capacities are distributed fairly evenly across Europe in the SNP-30 scenario means that curtailment is practically not required. Although the overall curtailment over a year is negligible, curtailment may occur sporadically for individual hours. Thus, the maximum curtailment in one hour in the SNP-30 scenario in 2050 amounted to 99 GW (compared to a total load of 436 GW).

4.2. Electricity transmission grid

As mentioned above, for the transmission grid considered in the analysis the entire European system has been divided into 118 power-exchanging areas. This grid is represented by corridors interconnecting the electricity centres (centres of gravity) of these areas. Power transfers among areas are expected to cover long distances, which makes the installation of HVDC reinforcements most attractive. The modelling results show that reinforcements to the interregional transmission grid in the long term are typically based on HVDC technology. The

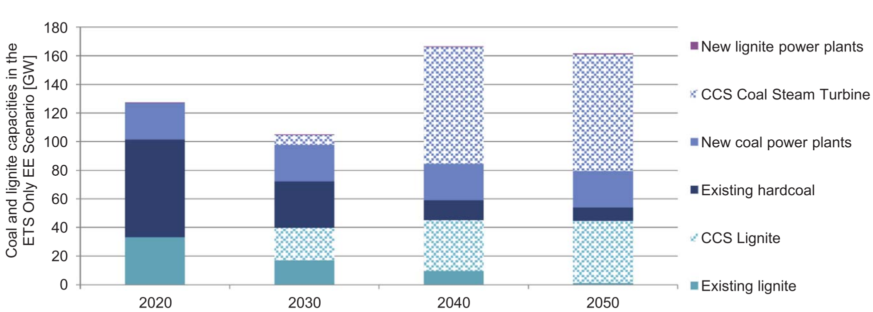

Fig. 5. Electric capacity of coal and lignite power plants in the ETS-Only EE scenario.

Table 5
Transmission network developments in the EU28 in the 2030 and 2050 timeframes.

	2030			2050		
	ETS-Only EE	Quo-30	SNP-30	ETS-Only EE	Quo-30	SNP-30
DC Lines Built [GW]	35	47	70	191	321	302
DC Lines Built [GW*'000 km]	9.9	12.8	18.9	52	85.5	80.7
Converters Built [GW]	34	38	64	135	195	184

possibility to install AC instead of HVDC was considered as an option for shorter interconnections among areas, but was discarded after comparing the relative merits of this with HVDC.

Table 5 provides the overall capacity of lines and AC/DC converters installed in the European system in each of the scenarios and time horizons considered. For lines, both their overall capacity and their overall dimensions in terms of capacity and length are provided.

Table 5 shows that investment in lines goes hand in hand with those in converters because the lines are HVDC. Overall investments in HVDC interconnectors required for the 2030 horizon range between 9.9 TW*km and 18.9 TW*km, depending on the scenario considered, while they are significantly larger in the 2050 horizon, ranging between 52 TW*km and 80.7 TW*km.

In both time horizons, the need for reinforcement is significantly smaller in the ETS-Only EE scenario (9.9 TW*km and 52 TW*km in the 2030 and 2050 time horizons, respectively) than in QUO-30/SNP-30 due to the lower RES-E share and the typical location of RES generation further away from main load centres than conventional generation. In addition, the variability of RES-E output results requires a larger development of the network than a scenario with more conventional generation technologies in the system.

When comparing the need for reinforcement under a quota obligation (QUO-30) with technology-specific feed-in premiums (SNP-30), a distinction must be made between the two time horizons of 2030 and 2050. Higher network costs were expected to result under the QUO-30 scenario, because this enables several existing technologies to compete freely and should result in spatially more concentrated RES generation. However, the results show that this is not the case in the 2030 time horizon. Reinforcements of interconnections among areas in the 2030 time horizon in the QUO-30 scenario amount to 12.8 TW*km, while those in the SNP-30 scenario amount to 18.9 TW*km. For low to medium RES penetration (ca. 50% RES-E share), aspects like the geographical distribution of new RES generation relative to the location of conventional capacity have a larger impact on network development costs than the concentration of RES generation in specific areas. Significantly changing the distribution of generation capacities in the system when replacing conventional capacity with variable RES-E, as in the SNP-30 scenario, results in larger changes in flow patterns than when installing additional RES capacity mainly in areas where generation capacity already exists, as is the case in QUO-30.

However, for the higher RES-penetration (ca. 70%) achieved in the 2050 time horizon, the relative size of flows produced by new RES generation becomes a more relevant driver of network reinforcements than the local distribution of new RES generation relative to conventional capacity. Thus, the reinforcements of the regional transmission grid in the 2050 time horizon in the QUO-30 scenario amount to 85.5 TW*km, while those in the SNP-30 scenario amount to 80.7 TW*km. In this case, concentrating RES generation in a few locations a long distance from most of the load centres they serve, as is the case in the QUO-30 scenario, results in very large flows covering large distances. These require slightly larger overall network reinforcements than the smaller flows caused by a more evenly spread RES generation driven by national support policies, as is the case in the SNP-30 scenario. This applies even when the geographical distribution of RES generation in the QUO-30 scenario resembles traditional conventional generation more than the distribution of RES generation in the SNP-30 scenario.

In order to explain the differences in transmission network reinforcements between the QUO-30 and SNP-30 scenario, we provide country-specific insights into reinforcement needs below.

4.2.1. Country-specific insights into transmission network reinforcement needs by 2030 in QUO-30 and SNP-30

One main reason for higher transmission grid investment needs in SNP-30 compared to QUO-30 is the location of solar PV capacity. In the SNP-30 scenario, PV power plants are mainly installed in areas with low generation capacity and weak grids. New net power feed-in and withdrawals caused by PV cannot be absorbed by the existing AC grid. Hence, new HVDC lines and converters need to be installed in this scenario. In addition, most of the main power-importing countries like Germany, Italy, and Spain have the largest realisable potential for RES-E deployment in the medium term, taking into account non-economic barriers. Thus, in the QUO-30 scenario, new RES-E capacity is concentrated more in these countries rather than in power-exporting countries like France. This contributes to decreasing imports into the former and exports from the latter. Tables 8 and 9 in the Annex show the net exports per country in Europe in the 2030 timeframe and the overall RES and thermal generation production for both scenarios.

An exception to this is the UK, a traditional importer of electricity, where RES-E generation investments in the 2030 timeframe are larger in the SNP-30 scenario than in QUO-30. Although this suggests lower imports in the SNP-30 scenario, larger reductions in conventional generation capacity taking place in SNP-30 lead to a larger increase in net imports into the country and, therefore, an increase in transmission grid investment needs. Net imports of electricity into most of the largest countries in Europe that have traditionally been power importers are larger in the SNP-30 scenario than in QUO-30 by 2030, leading to larger network investments in the former.

For Italy, contrary to what occurs in other importing countries, net imports are larger in the QUO-30 scenario. However, the favourable location of RES-E generation within the country makes it possible for RES-E to be integrated into the grid at a lower cost than conventional generation. Given that renewables generation is more abundant in QUO-30, relative changes in overall network development costs for Italy follow the general trend and lead to larger cross-border flows and reinforcements of international interconnections in SNP-30 than in QUO-30. In the set of scenarios considered, a large fraction of new RES generation within Italy (more than 50% of it) is installed in the north of the country. Then, increasing the penetration of RES generation, as occurs in the QUO-30 case with respect to other cases, results in more generation capacity installed in this area compared to other areas, which decreases the imbalance within this area. This reduces the network development required to host power exchanges between this and other areas, largely in the south of the country.

4.2.2. Country-specific insights into transmission network reinforcement needs by 2050 in QUO-30 and SNP-30

In the 2050 timeframe, the relative distribution of new RES-E generation across importing countries in Europe is similar to the 2030 horizon in both the SNP-30 and QUO-30 scenarios. Increases in RES-E generation in most importing countries are larger in the QUO-30 scenario than in SNP-30. Tables 10 and 11 in the Annex provide the net export and overall RES-E and thermal power production per country in

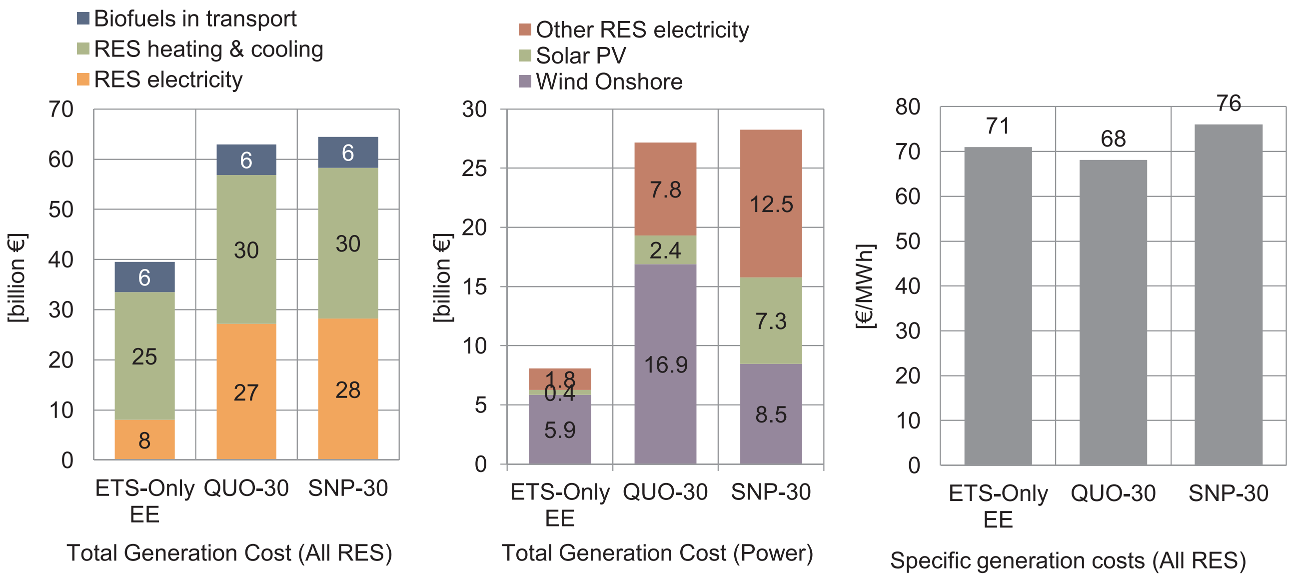

Fig. 6. Total generation costs and generation cost of RES per unit of electricity generated by 2030.

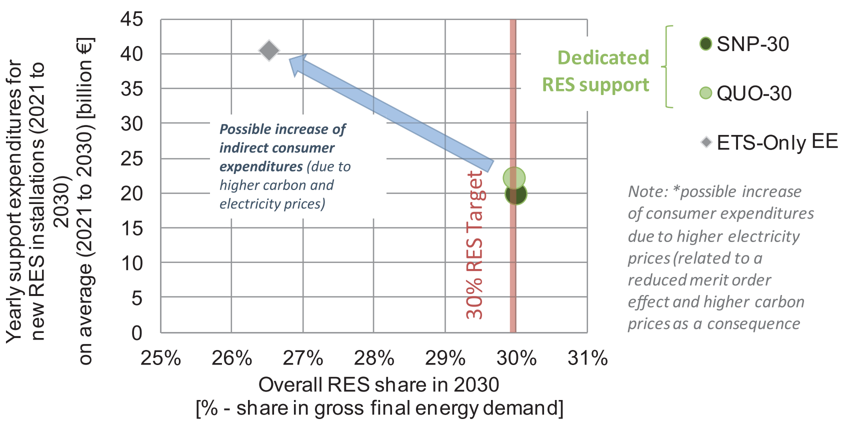

Fig. 7. RES deployment by 2030 and the corresponding (annual average) support expenditures for new RES (installed 2021–2030) in the EU 28.

the SNP-30 and QUO-30 scenarios in the 2050 timeframe. However, there are also some relevant differences between the two time horizons in the distribution of generation across Europe:

First, most of the main exporting countries in 2050 make larger RES-E generation investments under the QUO-30 scenario than under SNP-30. These include the Nordic countries and countries in south-western Europe, namely Bulgaria, Romania, and Greece. In France, the most relevant electricity exporter, RES-E investments are similar in both scenarios, but there are stronger differences in the 2030 timeframe.

Second, there are some power-importing countries like Germany and Italy, where large amounts of thermal generation combined with CCS are installed in the SNP-30 scenario. Then, despite the relatively small amount of RES-E generation installed in these countries in SNP-30, overall electricity generation is larger than in the QUO-30 scenario. This contributes to decreasing power exchanges in these countries in SNP-30.

The overall result is that imbalances and power exchanges among countries in the 2050 timeframe become larger in QUO-30 than in SNP-30. Power flows produced by new generation in QUO-30 are also larger than in SNP-30. This drives network investments up, and more than compensates for the fact that more RES-E generation is installed in isolated areas in SNP-30 than in QUO-30. Isolated RES-E generation mainly comprises wind offshore in the UK, and solar PV in France and Italy. Consequently, network investments in 2050 are larger in QUO-30 than in SNP-30.

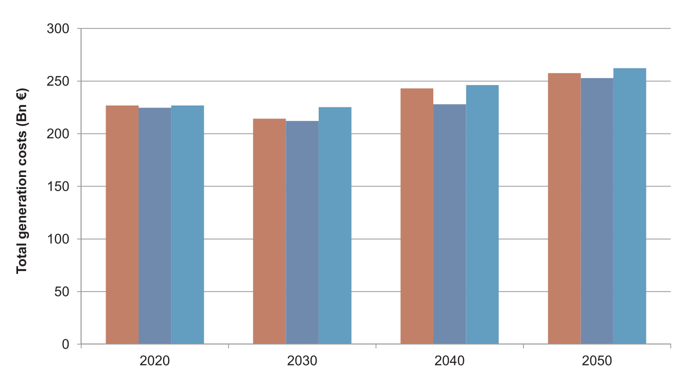

Fig. 8. Annual system costs of the EU power system in billion €2010 (excluding CO_2 costs).

4.3. Development of costs

4.3.1. Generation and support costs for renewable technologies

The modelled deployment pathways involve certain costs related to energy supply (additional generation costs), but also support payments. In a first step, we compare the generation costs arising from the installation, operation and maintenance of a renewables installation.

Fig. 6 shows the total generation costs of new RES installations in the forthcoming decade on the left, broken down by energy sector (electricity, heating & cooling and transport), and the corresponding specific generation costs on the right. The middle part of Fig. 6 provides a further detailed breakdown of total generation costs for renewables in the electricity sector at technology level. All the costs are expressed as a yearly average for the period 2021–2030, referring to the energy output of RES plants installed in the forthcoming decade 2021–2030).

Provided that more RES-E is generated, the overall generation costs in both 30%-target scenarios are higher than in the ETS-Only EE scenario. Costs for the SNP-30 scenario are slightly higher than for QUO-30 due to a more diversified exploitation of RES potentials. Looking at the specific generation costs on the right of Fig. 6, the lowest costs occur in the QUO-30 scenario. The costs of renewable energy in a scenario supported only by the ETS are higher due to the higher financing costs here resulting from the greater uncertainty of future revenues associated with the ETS compared to a dedicated renewables policy. On the other hand, the costs of renewable electricity would be lower if we assumed a reduction of the weighted average costs of capital compared to the standard figures – for example, due to proactive risk mitigation or positive general economic trends leading to an improved investment climate.

In addition to the generation costs of RES technologies, we analyse the distributional effects in terms of the costs occurring only for selected economic agents. These distributional effects determine how the system-related additional costs are distributed among consumers and producers. We show the annual support expenditures borne by electricity consumers and compare them based on the different RES development pathways. Fig. 7 shows that the support expenditures for dedicated RES support (in the 30%-target scenarios) range from € 20 – 22 billion, whilst the ETS-Only EE scenario leads to considerably higher support payments of € 41 billion on average. The high support expenditures in the ETS-Only EE scenario can be explained by the ETS mechanism, where the marginal technology required to fulfil the emission reduction target sets the price. All other technologies with lower abatement costs receive higher revenues thanks to the uniform CO_2 price. This leads to increased profits for more cost-competitive RES-E projects. In contrast, lower CO_2 prices due to the dedicated RES support applied in the QUO-30 and the SNP-30 scenarios reduce these increased profits. The technology-specific support in SNP-30 leads to slightly lower support expenditures than QUO-30, where technology-uniform support is applied for the RES-E sector.

4.3.2. Annual system costs

The annual system costs shown in Fig. 8 include fuel costs, operating costs and annual capital costs calculated using the annuity method for all generation technologies, storages and grid connections between countries. Existing infrastructures (plants, grids) are valued with the 2020 cost figures although these are considered sunk costs and therefore not included in the optimisation procedure. It should be taken into account that this is a simplification, given that the costs of past installations may deviate considerably from the 2020 cost figures. This is especially relevant for technologies with a very dynamic cost development such as solar PV. However, this approximation improves, the further we look into the future, because the share of existing power plants decreases over time. Furthermore, this simplification does not affect the absolute cost difference between different scenarios and therefore does not alter the key conclusions derived from this work. The annual system costs focus on the costs of supplying electricity and do not consider the costs resulting from changes in energy efficiency or any other changes on the demand side.

One can observe a moderate increase in annual system costs after 2020 by about 12–15% until 2050 (Fig. 8). This development is mainly because electricity demand increases by 22% between 2030 and 2050. Furthermore, the almost complete decarbonisation of the energy system causes substantial additional investment needs in low-carbon generation technologies and infrastructure, particularly towards the end of the modelling period. The use of dedicated RES-E policies in the QUO-30 and the SNP-30 scenarios causes a shift from coal plants based on CCS to wind and solar plants in particular. If no dedicated RES-E policies are applied after 2020, the use of RES-E is somewhat lower and CCS technologies are used to lower carbon emissions. The generation costs of CCS technologies are not necessarily lower than those of RES power plants, but despite this, CCS technologies can develop since there is no direct competition between RES power plants and CCS technologies due to the modelling logic.

It becomes evident that the cost development between scenarios varies only slightly. The least-cost resource allocation of RES-E assumed under the QUO-30 scenario leads to slightly lower total system costs than in the ETS-Only EE scenario by 2030. Whilst annual system costs in the ETS-Only EE scenario amount to € 214 billion by 2030, system costs in the QUO-30 scenario add up to € 212 billion. In the longer term by 2050, the annual system costs are estimated at € 258 billion for the ETS-Only EE scenario and € 253 billion for the QUO-30 scenario. The SNP-30 scenario is characterised by similar total system costs to the ETS-Only EE scenario, but involves slightly higher grid expansion costs.

Fig. 9 shows that the share of transmission grid costs in total system costs is very limited, amounting to less than 1% of overall system costs by 2030 and to 1.6–2.6% by 2050. The same applies to storage costs that make up around 2% of overall system costs. Generally, it was found that, besides the existing pump-storage hydropower plants, there is only a very limited need for additional innovative storage technologies such as CAES or batteries. The cost-optimal solution to provide the flexibility needed by the system is mainly based on a balanced portfolio of transmission extension, hydro storage and peak power plants. As stated above, the shift from the ETS-Only EE path to scenarios based on dedicated policies supporting RES development results in a shift of cost components for CCS-based coal and lignite to wind and solar technologies, leaving the overall costs more or less unchanged.

When the annual system costs are broken down to a unit of electricity generated (see Table 6), the specific generation costs, i.e. the total costs as a fraction of electricity demand excluding CO_2 costs, decrease by between 2.8% (SNP-30) and 5.5% (QUO-30) between 2020 and 2050. The main reason is that technology learning reduces the specific generation costs of the individual generation technologies. Looking at 2030, costs in the QUO-30 scenario are lower than in the ETS-Only EE scenario. In contrast, the development of more cost-intensive renewable technologies involves higher average costs by 2030, but technology learning and scale effects then bring costs back to a cost level similar to that of the ETS-Only EE scenario. By 2050, all three scenarios are characterised by very similar specific system costs

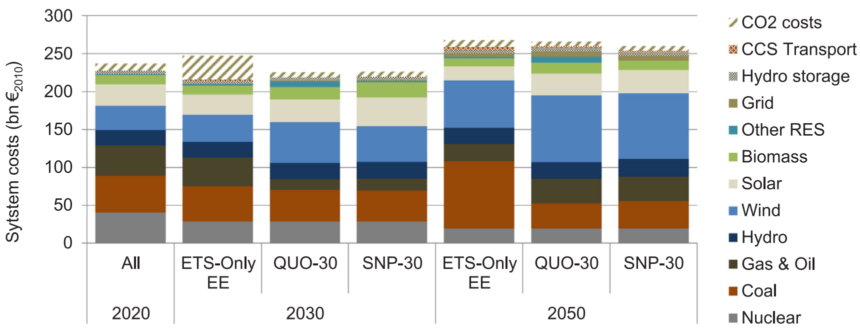

Fig. 9. Cost components of the annual overall system costs in the EU28.[6]

amounting to 63 €/MWh in the QUO-30 scenario, 64 €/MWh in the ETS-Only EE scenario and 65 €/MWh in the SNP-30 scenario. The average specific costs of renewable technologies (see Table 6) decrease over time in all three scenarios as a result of cost reductions over time, whilst the average specific costs of conventional technologies show a considerable increase due to a higher share of CCS-based power plants and higher fuel prices.

The results of this analysis show that the costs associated with higher shares of RES-E in the scenarios remain moderate and do not lead to higher electricity generation costs. This means that increasing the share of RES in the electricity system can be achieved without major impacts on the specific electricity generation costs. If this is considered together with the further additional benefits of RES such as reducing the dependency on fossil fuel imports, it seems beneficial to implement a specific RES-target in the order of 30% by 2030. As shown by (Duscha et al., 2016, 2014), the overall macro-economic impacts of stronger RES deployment are mainly due to the ratio of additional investments and additional avoided fuels as positive drivers and additional system costs as negative drivers.

4.3.3. Transmission grid infrastructure and costs

Table 7 shows the increase in network costs with respect to baseline (2020) levels per unit of electric energy produced in each time horizon and scenario. Changes in transmission network costs across time horizons and scenarios go hand in hand with changes taking place in the magnitude of network investments discussed in the previous section. Network integration costs are lowest in the ETS-Only EE scenario, where RES-E penetration levels are lower than in the QUO-30 and SNP-30 scenarios. This is in line with other studies conducted (Holz and von Hirschhausen, 2013; ECF, 2010; European Commission, 2011; Couckuyt et al., 2015; Gaxiola, 2012), which conclude that network development costs tend to develop in line with the level of RES-E penetration in the system. The network integration costs for the QUO-30 and SNP-30 scenarios depend on several parameters, namely the spatial distribution of RES generation relative to load and conventional generation and the RES penetration level achieved. In the 2030 time horizon, network costs are largest in the SNP-30 scenario, while they are largest in the QUO-30 scenario in the 2050 horizon.

In any case, the network development costs required to achieve the climate policy targets in any of the scenarios considered are significantly lower than the generation investment and operation costs. Network development costs per unit of electrical energy produced are between 50 and 400 times smaller than the overall system costs. Thus, network development costs range between 0.16 €/MWh for the ETS-Only scenario in 2030 and 1.50 €/MWh for the QUO-30 scenario in 2050. In contrast, the total system costs are more than 60€/MWh in all the scenarios and time horizons considered. As a result, it can be reasonably assumed that the impact of clean energy policies and the corresponding development of generation on regional transmission costs should not be the most relevant factor tilting the balance in favour of one set of policies or another.

5. Summary, conclusions and policy implications

This study estimated the future costs of the European power sector for different target levels and policy options for renewable energies until 2030 and 2050 with a focus on the supply side. Estimating the impacts of different RES targets requires modelling tools with a high level of detail regarding the costs and potentials of RES use, power sector development and operation as well as grid development and operation. Therefore, the chosen modelling approach combines three different models: First, Green-X to map the development of RES with a detailed representation of policies and RES-potentials; second, Enertile to model long-term investment decisions in the power sector and power system operation; and third, TEPES to assess the development and operation of grid infrastructure. We analyse the impact that the location and type of RES generation has on power system and network costs based on a high geographical and temporal resolution.

The modelling results show that, by 2030, the overall power system costs are slightly lower in the QUO-30 scenario with a European RES quota than in the ETS-Only EE scenario, whilst system costs in the SNP-30 scenario with purely national policies are slightly higher. The low cost differences can be explained in particular by the trade-off between the risk-mitigating effect of a stable policy framework and the least-cost deployment under an ETS-only policy. The analysis showed that there is no increase in the overall system costs in the power sector with a 30% RES-target compared to a scenario with a purely GHG emission reduction target leading to a RES-share of about 27%. In this context, it is crucial to highlight the high sensitivity of system costs towards capital costs when decarbonising the power sector. According to analyses by (Hirth and Steckel, 2016), an increase in the WACC from 3% to 15% leads to a decrease of the RES-E share from 40% to almost 0 in the cost-optimal electricity mix when assuming a CO_2 price of USD 50 per ton. Our modelling also shows that, even assuming RES-E shares in the order of 70%, grid expansion and reinforcement is still more cost-efficient than the use of storage technologies.

The results of this analysis indicate that the RES target proposed by the European Commission in its winter package "Clean Energy For All Europeans" (European Commission, 2016) can be considered only moderately ambitious and that higher RES deployment than the minimum target might be economically beneficial. According to the recently conducted in-depth macro-economic impact assessment (Duscha et al., 2016, 2014), a RES target of 30% / 35% leads to an increase of GDP by up to 0.4% / 0.8% and to increased net employment by about 0.3% / 0.7% by 2030 compared to a 26% RES-target. Additional benefits arise from the increased security of supply (e.g. cutting imports of natural gas by up to 60% by 2030 in

[6] The RES system costs are an output of Green-X; the costs for extending and reinforcing the transmission grid are shown against the network in 2020 and are an output of TEPES, and the remaining cost components are results from Enertile.

Table 6
Development of specific system costs.

	Scenario	Unit	2020	2030	2040	2050
Total Energy System costs (incl. grid costs)	ETS-Only EE	$€_{2010}$/MWh	67	65	65	64
	QUO – 30	$€_{2010}$/MWh	67	64	61	63
	SNP – 30	$€_{2010}$/MWh	67	68	66	65
Avg. specific costs of RES (based on Entertile)	ETS-Only EE	$€_{2010}$/MWh	69	61	54	53
	QUO – 30	$€_{2010}$/MWh	67	63	59	57
	SNP – 30	$€_{2010}$/MWh	69	69	62	57
Avg. specific costs of conventional technologies	ETS-Only EE	$€_{2010}$/MWh	62	62	73	83
	QUO – 30	$€_{2010}$/MWh	61	56	63	81
	SNP – 30	$€_{2010}$/MWh	61	57	63	82

Table 7
Increase in transmission network costs per unit of electricity produced.

	2020	2030			2050		
		ETS-Only EE	***Quo-30***	***SNP-30***	***ETS-Only EE***	***Quo-30***	***SNP-30***
Annualised Reinforcement Costs [M€]	–	570	690	1105	4181	6673	6341
Increase in Transmission Network Costs [€/MWh]	–	0.16	0.19	0.30	0.95	1.50	1.43

the 35%-RES scenario compared to the reference scenario) and further environmental benefits. Therefore, the complementary instruments and measures currently being negotiated between the EU Parliament and the EU Council to facilitate RES deployment in the electricity sector should consider the potential benefits of target overachievement. These measures could for example include common design criteria for implementing best practices for auctions of RES capacity, or an EU fund to mitigate the current investment risks in Member States affected by the financial crisis. Furthermore, the 2030 governance should enable ambitious integrated national energy and climate plans combined with an integrated regional planning of generation assets and grid infrastructure in order to lower the total system costs.

In addition to the overall generation costs of the system, we analysed the distributional effects of RES-E support after 2020. If energy and carbon prices do not change considerably in forthcoming years, dedicated financial support will be necessary for new RES installations post 2020 to achieve 2030 RES targets at reasonable cost. As shown in the modelling test with the Green-X model, the consumer burden under dedicated RES support may even be half of that in the case where the ETS acts as the only driver to trigger investments in low-carbon technologies.[7] The reason is the high windfall profits in an ETS-Only EE case, where the amount depends on the steepness of the CO_2 abatement curve.

According to our analysis, RES-E share levels of up to 70% by 2050 involve only limited infrastructure costs at the transmission level, amounting to less than 1% of overall system costs by 2030 and to 1.6–2.6% by 2050. This means that, in terms of cost considerations, political decisions affecting the power mix are more relevant than policies related to transmission network planning. It should be noted that the development of the distribution grid was not part of our analysis.

Comparing the network costs associated with the different policy support schemes for RES yields unexpected results. For medium RES penetration levels (ca. 50%), the transmission network development costs resulting from an EU-wide optimal deployment of RES generation under an EU-wide quota obligation (QUO-30) are lower than the network costs incurred when countries use national and technology-specific feed-in premiums (SNP-30). This finding appears counter-intuitive at first glance, since one would expect higher grid-related investments for a RES-development characterised by a stronger geographical concentration of RES-E capacity under an EU-wide quota compared to a more balanced geographical distribution of RES-E power plants assuming national RES targets and technology-specific policies. A closer look at the results on a national level reveals that the relevant drivers of transmission costs include the location of RES generation with respect to already existing (conventional) generation. Thus, not only a concentration of renewable capacity is relevant for grid investments, but a concentration of renewable and conventional capacity in combination with the grid infrastructure. On the other hand, for higher RES penetration levels (ca. 70%), centrally planning the expansion of RES generation (QUO-30) results in higher transmission network costs than when countries establish their own targets in line with national policies (SNP-30). Consequently, the impact of different RES policies on the development of grid costs depends on the RES-E share. This finding demonstrates the necessity for a more detailed analysis that considers the geographical distribution of power plants and the network infrastructure. Additional effects such as the role of on-site RES-E generation from small PV power plants and their impact on the power system and the grid infrastructure at the distribution level could be analysed in future research.

Finally, we would like to highlight that the results discussed focus on power supply without taking into account the option of further reducing electricity demand. A first joint consideration of measures on the supply side and the demand side has been undertaken by (Held et al., 2015). This represents a first attempt to compare costs without creating a link between supply-side and demand-side models. We believe that further research combining supply-side and demand-side models is needed in order to be able to balance CO_2 mitigation costs on the supply side and the demand side.

[7] Compare the results on support expenditures under the QUO-30 and SNP-30 scenarios – both offering dedicated support to new RES installations – with the related outcomes in the ETS-Only EE scenario.

Acknowledgements

This research was commissioned by the German Ministry for

Economic Affairs and Energy (BMWi) and the Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ). It reflects the authors' work and views and not those of the contracting authorities. We would like to thank our contracting authority for the opportunity to carry out this research project, and for the highly constructive discussions of the topic. Special thanks go to our project partners for their support and valuable inputs to this paper.

Appendix: Auxiliary tables

See Tables 8–11 here.

Table 8
Net exports per country in Europe in the 2030 timeframe for the QUO-30 and SNP-30 scenarios.

	Net_Export [GWh]			Net_Export [GWh]	
	SNP-30	QUO-30		SNP-30	QUO-30
AL	−152	−201	**LU**	−490	−830
AT	8812	15142	**LV**	−1129	−1134
BA	−44	−50	**MA**	0	−2
BE	−18361	−12272	**ME**	−96	−142
BEL	−78	−86	**MK**	−67	−107
BG	6046	8989	**MOLDOVA**	−14	−8
BI	−58	−60	**MT**	0	0
CH	−485	−4026	**NI**	16686	1278
CY	0	0	**NL**	−9254	−6038
CZ	−2285	−1522	**NO**	52292	49472
DE	−58845	−54263	**NORTH**	0	0
DK	−3916	−4446	**PL**	−16393	−13420
EE	−1638	−1659	**PT**	−3883	6571
ES	−69541	−49014	**RO**	−5512	−1841
FI	3735	425	**RS**	−171	−273
FR	243344	207206	**RU**	−108	−82
GR	−4601	−3726	**SE**	−24354	−28087
HR	−1544	1458	**SI**	−87	−323
HU	−1423	−1086	**SK**	−450	−663
IE	−881	−3150	**TR**	−40	−103
IT	−51722	−64467	**UA**	−140	−217
LT	3243	2172	**UK**	−56396	−39415
			Total_Import	−215573	−200028

Table 9
Overall RES and thermal generation production in the 2030 time horizon for the QUO-30 and SNP-30 scenarios.

	Total RES		Total Thermal			Total RES		Total Thermal	
	QUO-30 GWh	SNP-30 GWh	QUO-30 GWh	SNP-30 GWh		QUO-30 GWh	SNP-30 GWh	QUO-30 GWh	SNP-30 GWh
AL	0	0	0	0	**LU**	1392	1758	7245	7235
AT	78798	74127	5451	6047	**LV**	5629	5962	1835	1673
BA	0	0	0	0	**MA**	0	0	0	0
BE	26294	26174	57509	52422	**ME**	0	0	0	0
BEL	0	0	0	0	**MK**	0	0	0	0
BG	19341	17057	23569	23569	**MOLDOVA**	0	0	0	0
BI	0	0	0	0	**MT**	354	393	1757	1802
CH	44968	48690	21399	21222	**NI**	13009	29898	1487	85
CY	1648	1870	5619	5667	**NL**	49802	48952	58387	57772
CZ	16241	19591	61900	59565	**NO**	185476	186098	57	19
DE	288749	249531	221584	266298	**NORTH**	0	0	0	0
DK	21363	23157	9323	9308	**PL**	63530	68257	99297	95140
EE	2852	3495	3838	3116	**PT**	57350	42722	10807	11985
ES	225368	194666	62278	76143	**RO**	38226	32883	24011	26957
FI	32861	35220	42661	42483	**RS**	0	0	0	0
FR	240742	281779	476908	477592	**RU**	0	0	0	0
GR	42043	44406	25340	25563	**SE**	99825	106066	7142	6675
HR	15357	14654	6431	4199	**SI**	9543	10237	6119	6172
HU	11973	11737	35246	35966	**SK**	12027	12600	24219	24415
IE	24568	27911	7589	6346	**TR**	0	0	0	0
IT	228250	208956	64570	112950	**UA**	0	0	0	0
LT	3662	5153	10481	10470	**UK**	160454	231332	172895	90530

Table 10
Net exports per country in Europe in the 2050 timeframe for the QUO-30 and SNP-30 scenarios.

	Net_Export [GWh]			Net_Export [GWh]	
	SNP-30	QUO-30		SNP-30	QUO-30
AL	−274	−196	LU	−2318	−2769
AT	8135	16233	LV	1101	676
BA	−34	−36	MA	0	−2
BE	−28125	−21902	ME	−244	−316
BEL	−143	−104	MK	−303	−376
BG	9887	27853	MOLDOVA	−24	−19
BI	−109	−136	MT	0	0
CH	−12161	−9467	NI	31918	5282
CY	0	0	NL	−37680	−30638
CZ	12063	12138	NO	89667	100573
DE	−115624	−137081	NORTH	−1	−14
DK	−5315	−2981	PL	13606	18776
EE	414	3492	PT	−3991	−421
ES	−85752	−63377	RO	18282	30156
FI	−9452	−7486	RS	−846	−958
FR	219335	205982	RU	−163	−75
GR	27380	34739	SE	2095	16643
HR	−1779	1195	SI	7323	7320
HU	−16051	−16622	SK	−5958	−7538
IE	15158	5665	TR	−65	−60
IT	−112186	−121919	UA	−589	−445
LT	7040	8667	UK	−24217	−70453
			Total_Import	−387006	−381306

Table 11
Overall RES and thermal generation production in the 2050 time horizon for the QUO-30 and SNP-30 scenario.

	Total RES		Total Thermal			Total RES		Total Thermal	
	QUO-30 [GWh]	SNP-30 [GWh]	QUO-30 [GWh]	SNP-30 [GWh]		QUO-30 [GWh]	SNP-30 [GWh]	QUO-30 [GWh]	SNP-30 [GWh]
AL	0	0	0	0	LU	3040	2825	6613	6797
AT	110900	101531	96	93	LV	9839	10083	11	29
BA	0	0	0	0	MA	0	0	0	0
BE	36112	30555	65016	64561	ME	0	0	0	0
BEL	0	0	0	0	MK	0	0	0	0
BG	29005	24660	40176	25671	MOLDOVA	0	0	0	0
BI	0	0	0	0	MT	595	588	1681	1697
CH	54328	52639	15536	15300	NI	21391	49827	681	0
CY	3439	3650	4623	4535	NL	87841	80127	29862	32293
CZ	33157	32690	75773	76051	NO	253130	242591	0	0
DE	387838	355501	135990	191544	NORTH	0	0	0	0
DK	36688	35142	696	469	PL	167481	167794	51153	42957
EE	13320	10337	0	0	PT	77030	62162	306	8669
ES	333132	294281	44713	59425	RO	58476	46787	53480	52652
FI	48146	45878	26614	26479	RS	0	0	0	0
FR	508355	519538	304125	306485	RU	0	0	0	0
GR	81184	80037	37772	34528	SE	152275	138337	0	0
HR	27955	24505	0	0	SI	12982	12680	12977	13322
HU	22427	19481	27190	29439	SK	19448	18781	18077	18572
IE	49489	64452	4377	0	TR	0	0	0	0
IT	365630	340323	36672	66657	UA	0	0	0	0
LT	14118	12430	8680	8760	UK	295772	403880	129115	67875

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